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Interior Board of Land Appeals
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July 13, 2015

IBLA 2013-211	)	MMS-09-0104-O&G
	)	
CONOCOPHILLIPS CO.	)	Onshore Oil & Gas Royalties
	)	
	)	Decision Affirmed

ORDER

ConocoPhillips Co. (COPC) has appealed from a June 20, 2013, decision (Decision) of the Director, Office of Natural Resources Revenue (ONRR), MMS-09-0104-O&G, granting in part and denying in part COPC's appeal of ONRR's November 3, 2009, Order to Perform Restructured Accounting and Pay Additional Royalties (Order to Pay).[1] The Order to Pay required COPC to pay additional royalties, in the total amount of $44,813.45, for sample months, and otherwise to compute and pay additional royalties for all non-sample months, during the period from September 1, 2002, through December 31, 2007, owing to a "systemic" error in royalty valuation. Order to Pay at 2. The Order to Pay pertains to all of the natural gas produced from COPC's Federal onshore oil and gas leases that was transported by the San Juan Gathering System, from its wells to a nearby processing plant.[2] The Director's Decision upheld the Order to Pay's conclusion that COPC had erred in calculating royalties due the United States by failing to place the gas in a marketable condition at no cost to the Federal government. In particular, the Director agreed with ONRR that COPC improperly deducted the costs of compressing the gas in the field from the gross proceeds received on the sale of the gas, in valuing it for royalty purposes.

[1] ONRR's onshore royalty collection responsibilities were formerly undertaken by the Minerals Management Service (MMS). References herein to ONRR refer to MMS or ONRR, as appropriate.

[2] The San Juan Gathering System was, at all relevant times, owned by Enterprise Field Services, LLC (EFS), or its predecessor-in-interest El Paso Field Services Company (EPFS). References hereinafter to EFS, which is a subsidiary of Enterprise Products Partners L.P., will refer to EFS or EPFS, as appropriate.

EXHIBIT 1-1

Because COPC has not demonstrated any error in ONRR's determination to require COPC to perform restructured accounting and pay additional royalties, we affirm the Director's Decision.[3]

Factual and Procedural Background

At issue in this case is the computation and payment of royalties for natural gas produced by COPC from numerous wells on Federal leaseholds in the San Juan Basin, New Mexico. During the relevant timeframe, gas produced from the leaseholds was moved by pipeline into EFS's San Juan Gathering System for transportation to a global compressor (also called the global compression project, or GCP), where the gas was compressed, raising its wellhead pressure of 5 to 110 pounds per square inch (psi) to up to 250 psi, prior to transportation to EFS's processing plant.[4] *See* Order to Pay at 3. At the processing plant, the gas went

[3] This administrative proceeding is subject to section 4(a) of the Federal Oil and Gas Royalty Simplification and Fairness Act of 1996 (FOGRSFA), 30 U.S.C. § 1724(h) (2012), which requires the Department to issue a "final decision . . . within 33 months from the date such proceeding was commenced." The time for issuing a final decision under FOGRSFA "may be extended by any period of time agreed upon in writing by the Secretary and the appellant," but if a final decision does not issue within that period, "a final decision in favor of the Secretary [shall be deemed to have issued] as to any monetary obligation the principal amount of which is $10,000 or more, and the appellant shall have a right to judicial review of such deemed final decision in accordance with Title 4." 30 U.S.C. 1724(h) (2012).

The 33-month period in this case began when MMS issued its 2009 Order to Pay, and ended on August 3, 2012. On Mar. 11, 2015, we issued a Show Cause Order why the appeal should not be dismissed because the 33-month deadline had expired. By response dated Mar. 13, 2015, counsel for COPC and ONRR submitted eight written agreements extending the 33-month period for processing the appeal; in the final agreement, the parties agreed to extend the deadline "until the date on which the Interior Board of Land Appeals renders a final decision on this appeal." Response to Show Cause Order at 2, Ex. 8. We therefore have jurisdiction to decide this appeal.

[4] EFS upgraded the transportation capacity of the San Juan Gathering System in 1998, in order to satisfy the increased production that corresponded to an earlier enhancement in the processing capacity of the plant in 1996. It did so not only by increasing its ability to compress gas in the field, but also by increasing the capacity of the pipelines running to the plant: "Specifically, EPFS's global compression project involved the installation of approximately 40,000 horsepower of additional compression and 50 miles of additional pipe." Decision at 4.

through a cryogenic turbo-expander process, resulting in the extraction of natural gas liquid products (NGLP), leaving a residue gas, which was further compressed to 800 to 1,200 psi. The NGLPs and residue gas were sold separately. The residue gas was returned to COPC at the tailgate of the processing plant, and placed in the mainline pipeline, which transported the gas for sale by COPC to the ultimate purchaser.

EFS charges COPC, under various agreements, for the costs of gathering, compressing, and processing the gas, either in the field, prior to transportation to the processing plant, or at the plant. In subsequently computing the royalty on the gas produced from COPC's leases and transported and processed by EFS, COPC deducted from the gross proceeds received on the ultimate sale of the gas, as a transportation allowance, all of the costs charged by EFS for gathering, compressing, and processing the gas. *See* Decision at 4.

Following an audit conducted by the State of New Mexico pursuant to section 205 of the Federal Oil and Gas Royalty Management Act of 1982 (FOGRMA), 30 U.S.C. § 1735 (2012), the State notified COPC, by letter dated April 1, 2009 (Audit Issue Letter), of its preliminary determination that COPC owed additional royalties based on COPC's improper deduction of the costs of compressing the gas from the gross proceeds received on the sale of the gas, as a transportation allowance, in valuing the gas for royalty purposes.[5] Audit Issue Letter at 3 ("Compression as determined by MMS is a cost to place gas in marketable condition; therefore, those fees and adjustments are a cost to put the gas in marketable condition and is not allowed per 30 C.F.R. § 206.152(i) (2006)."). By letter dated June 18, 2009, COPC responded to the audit, disputing the State's conclusion that the compression in the field was necessary to place the gas in a marketable condition, and stating that the compression was necessary to transport the gas to the processing plant, and thus the costs of compression were properly deductible as a transportation allowance. Letter of June 18, 2009, at 3 ("[T]he categorical statement that compression is not deductible is wrong and contrary to the applicable regulations and agency and court decisions addressing this issue.").

[5] The State audited royalty payments related to a total of 82 leases in 3 oil and gas units (San Juan 29-5 Mesa Verde (891-000437-0), San Juan 30-6 Mesa Verde (891-000538-0), and Northeast Blanco Mesa Verde (892-000929-0)) over a 3-month period in each of the 6 years from Jan. 1, 2002, through Dec. 31, 2007, finding that COPC owed $25,960.24. The State later focused on the period from Sept. 1, 2002, through Dec. 31, 2007, and also revised its calculation of the additional royalties due for the sample months during that time period, increasing the amount owed to $44,813.45, after correcting certain computational errors. The State noted further that, in addition to the $44,813.45, COPC likely owed additional royalties for the non-sample months.

On November 3, 2009, ONRR issued its Order to Pay, agreeing with the State's determination that COPC had committed a "systemic" error by improperly deducting, for royalty valuation purposes, the costs to compress the gas in the field. Order to Pay at 2. ONRR concluded that since the pressure in the field following compression did not exceed what was necessary to satisfy the marketable condition requirements of the mainline pipeline, the costs of compressing the gas after entry into EFS's transportation system constituted part of the process of rendering the gas suitable for sale. *See id.* at 3 ("[G]lobal compression is one of the first steps towards placing production in marketable condition."). ONRR ordered COPC to pay the additional royalties, totaling $44,813.45, already determined by the State audit to be due for the sample months, as well as compute and pay any additional royalties found to be due with respect to the non-sample months, for the period from September 2002 through December 2007. *See id.* at 5.

COPC appealed the Order to Pay to the Director in accordance with the procedures set forth in 30 C.F.R. Subpart B,[6] and on June 20, 2013, the Director, ONRR, issued his Decision from which COPC now appeals. In his Decision, the Director upheld ONRR's determination that compression was necessary to render the gas from COPC's wells suitable for placement in the mainline pipeline at the tailgate of the processing plant and therefore necessary for putting the gas in a marketable condition. *See* Decision at 4. As such, the Director concluded that the costs of compression were not properly deducted as a transportation allowance from the gross proceeds received on the sale of the gas, *see id.* at 6-8, and upheld ONRR's requirement that COPC pay additional royalties, in the total amount of $44,813.45, for the sample months, and perform restructured accounting and pay any additional royalties found to be due for the non-sample months, during the period from October 2002 through December 2007. The Director, however, declined to uphold ONRR's requirement with respect to the non-sample month of September 2002 because the obligation for payments during that month would have accrued more than 7 years prior to ONRR's November 2009 Order to Pay, and was therefore barred by the 7-year statute of limitations established by section 115(b)(1) of FOGRMA, 30 U.S.C. § 1724(b)(1) (2012). *See* Decision at 10-11.[7]

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[6] COPC filed its appeal and initial Statement of Reasons (SOR) on Dec. 9, 2009; a supplemental SOR on Aug. 27, 2010; and a second supplemental SOR on May 31, 2012.

[7] The Director rejected COPC's argument that ONRR was equitably estopped from requiring COPC to pay additional royalties resulting from the improper deduction because ONRR had not objected to the deduction in a prior audit. *See* Decision at 8 ("[E]stoppel does not lie where the effect of such action would be to grant a right not authorized by law, such as royalty valuation.").

COPC timely appealed from the Director's June 20, 2013, decision.[8]

Legal Framework

Under section 17(b)(1)(A) and (c)(1) of the Mineral Leasing Act, royalty on oil and gas produced from an onshore Federal oil and gas lease is properly computed as a percentage of the "amount or value of the production removed or sold from the lease." 30 U.S.C. § 226(b)(1)(A) and (c)(1) (2012). The regulations for valuing Federal gas, for royalty purposes, were, at all relevant times, set forth in 30 C.F.R. §§ 206.150 through 206.159 (2006).[9]

When valuing gas for royalty purposes, the lessee must base the value on the gross proceeds accruing to the lessee from sale of the gas. The regulations define gross proceeds as "the total monies and other consideration accruing to an oil and gas lessee for the disposition of the gas, residue gas, and gas plant products produced." 30 C.F.R. § 206.151 (2006). It "includes, but is not limited to, payments to the lessee for certain services such as dehydration, measurement, and/or gathering to the extent that the lessee is obligated to perform them at no cost to the Federal Government." *Id.*

In valuing unprocessed gas, 30 C.F.R. § 206.152(i) (2006) requires the lessee to value the gas based on the gross proceeds accruing to the lessee from its sale, less appropriate deductions under 30 C.F.R. §§ 206.156 and 157 (2006) for the reasonable actual costs of transporting the gas to a point of sale outside the lease. In valuing processed gas, 30 C.F.R. § 206.153(i) (2006) requires the lessee to value the

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[8] COPC filed a notice of appeal, an SOR and a supplemental SOR (SSOR). COPC stated in its SOR that it "adopts its prior Statements of Reasons transmitted to ONRR to the extent they address the issues presented in this [SOR]." SOR at 1 n.2. In adjudicating the issues raised in the current SOR, we therefore consider the arguments offered by COPC in its earlier pleadings.

[9] These regulations were promulgated effective Mar. 1, 1988. *See* 53 Fed. Reg. 1230, 1271 (Jan. 15, 1988). They were re-designated as 30 C.F.R. §§ 1202.150 through 1202.159, effective Oct. 1, 2010, without substantive change, to comply with Secretarial Order No. 3299, which restructured MMS, changing its name to the Bureau of Ocean Energy Management, Regulations, and Enforcement (BOEMRE), and separated the responsibilities previously performed by MMS and reassigned those responsibilities to three new agencies: ONRR, Bureau of Ocean Energy Management (BOEM), and Bureau of Safety and Environmental Enforcement (BSEE). *See* 75 Fed. Reg. 61051, 61066, 61067 (Oct. 4, 2010).

gas based on the combined value of the residue gas and all gas plant products derived from processing the gas, less appropriate deductions under 30 C.F.R. §§ 206.158 and 159 (2006) for the reasonable actual costs of processing the gas.

Whether valuing unprocessed or processed gas, the regulations require the lessee to put it in marketable condition at no cost to the Federal government. *See* 30 C.F.R. §§ 206.152(i) and 153(i) (2006). "Marketable condition" is defined as "lease products which are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the field or area." 30 C.F.R. § 206.151 (2006). The "marketable condition rule" reflects a longstanding principle of royalty valuation under which a lessee cannot deduct from the royalty value of the gas any of the costs incurred to place the gas in a marketable condition. *See Amoco Production Co. v. Baca*, 300 F. Supp. 2d 1, 7 (D.D.C. 2003), *aff'd*, 410 F.3d 722 (D.C. Cir. 2005), *aff'd*, 549 U.S. 84 (2012) ("The marketable condition rule is pivotal in the calculation of royalties because it affects the determination of a lessee's gross proceeds, and therefore the value of production [for royalty purposes]"); *The Texas Co.*, 64 I.D. 76, 79 (1957); 43 C.F.R. § 3162.7-1(a) ("The operator shall put into marketable condition, if economically feasible, all oil, other hydrocarbons, gas, and sulphur produced from the leased land.").

Discussion

The single issue presented in this appeal is whether COPC may deduct the cost of compressing the gas in the field prior to its transportation to the processing plant from the gross proceeds, as part of the transportation allowance, in calculating the royalty owed the United States. COPC maintains that "the purpose of compression was to ensure that the gas at issue could arrive at the plants for processing," *see* SOR at 4, and therefore the costs of compression are deductible as a transportation allowance. In contrast, the Director, ONRR, concludes that compression is necessary "to meet the requirements of the mainline pipeline which delivers the gas to the market," and therefore is necessary for placing the gas in a marketable condition; as such, the costs of compression are not deductible. *See* Decision at 5-6.

In challenging ONRR's order, COPC has the burden to demonstrate that ONRR erred in its determination that the costs of compression were costs incurred to place the gas in a marketable condition. *See Burlington Resources Oil & Gas Co.*, 183 IBLA 333, 352 (2013) (citing *Exxon Corp.*, 118 IBLA 221, 246 (1991) ("When valuation of production is challenged, an appellant must not merely show that the methodology is susceptible to error, but that an error, did, in fact, occur.")). As explained below, we find that COPC has not met its burden.

Under the Marketable Condition Rule for Processed Gas, Compression in the Field and During Processing May Serve to Place Gas in Marketable Condition

COPC first argues that, as a matter of law, ONRR incorrectly applied the marketable condition rule applicable to unprocessed gas (30 C.F.R. § 206.152(i) (2006)), rather than the marketable condition rule applicable to processed gas (30 C.F.R. § 206.153(i) (2006)), since processed gas was the gas ultimately sold by COPC in the present case. *See* SOR at 1, 2 ("The . . . residue gas and natural gas liquid[] [products] . . . are the royalty-bearing products"). COPC further argues that under 30 C.F.R. § 206.153(i) (2006), COPC cannot be required to place the gas in a marketable condition at no cost to the Federal government *before* the gas has been processed, as well as to place the processed gas in a marketable condition at no cost to the Federal government *after* the gas has been processed. *See id.* at 1, 5-7; Second SSOR, MMS-09-0104-O&G, dated May 31, 2012, at 4 ("[E]xpenses incurred to transport the unprocessed gas to a plant . . . to initiate processing cannot be subject to the marketable condition rule for processed gas because they do not represent costs incurred to make 'residue gas' or 'plant products' marketable. . . . [R]esidue gas and plant products do not exist until after processing.").

We agree with COPC that the applicable marketable condition rule is the rule governing processed gas—30 C.F.R. § 206.152(i) (2006)—which provides that "[t]he lessee must place residue gas and gas plant products in marketable condition . . . at no cost to the Federal Government." COPC, however, seeks to improperly bifurcate the entire process of bringing the gas from the wellhead, through the processing plant, to the tailgate of the plant into two steps: (1) bringing the unprocessed gas from the wellhead to the processing plant, and (2) processing the gas. COPC argues that the costs of compression that occurred as part of the first step are properly deducted as a transportation allowance. COPC believes that the regulation's requirement to place residue gas and gas plant products in marketable condition at no cost to the Federal government prohibits deduction *only* of the costs of compression of the processed gas, which in this case is the cost of compressing the residue gas so that it is suitable for transportation to the mainline pipeline at the tailgate of the processing plant. *See* SOR at 5 ("30 C.F.R. § 206.153(i) . . . reflects *no* obligation to place '*gas*' in marketable condition prior to processing. Instead, § 206.153(i) imposes an obligation to 'place *residue gas* and gas plant products in marketable condition['] . . . after processing has occurred." (Emphasis added)); SSOR at 4-5 n.2 ("[W]ith respect to processed gas, everything that occurs prior to processing should be entirely immaterial. All that should matter, with respect to residue gas, . . . is that compression at a plant tailgate should elevate its pressure to a point sufficient to enter an interstate pipeline.").

In support of its argument, COPC asserts that the compression in the field had "'no material benefit to the downstream residue gas mainline pressure,'" since it did not serve to increase the pressure of the processed gas to the point suitable for entry into the mainline pipeline at the tailgate of the processing plant. SOR at 4 (quoting Report of Kyle L. Pearson, dated Aug. 30, 2010 (Pearson Report) (Ex. J attached to SSOR, MMS-09-0104-O&G, dated Aug. 27, 2010), at 24).[10] COPC thus notes that "Pearson stated plainly that the global compression had little to no effect on post-plant pressures." *Id.* Rather, COPC states that the compression in the field only served to increase the pressure of the unprocessed gas, thereby promoting its transportation from the outlet of the field compressors to the processing plant. *Id.*

We disagree. In the present case, it is undisputed that once produced, the unprocessed gas was compressed in the field prior to being transported to the processing plant, raising the pressure from 5 to 110 psi up to less than 250 psi, and then, in the course of being processed at the plant into NGLPs and residue gas, was further compressed, raising the pressure up to 800 to 1,200 psi, prior to being placed in the mainline pipeline for transportation to market.[11] Regardless of whether the unprocessed gas coming from the wellhead needed to be compressed up to a psi of less than 250 in order to be transported to the processing plant, the gas ultimately had to have a pressure of 800 to 1,200 psi in order to be marketable. Thus, whether the increase in pressure from 5 to 110 psi up to 800 to 1,200 psi occurred in one step or over the course of two steps, all of the costs of compressing the gas up to the pressure demanded by the available market must be considered in the costs of placing the gas in a marketable condition. In these circumstances, we agree with ONRR that both the compression in the field and the compression at the processing plant constituted compression necessary to place the processed gas that was ultimately sold in a marketable condition.

[10] Pearson, who has 25 years of experience "working in the pipeline and hydrocarbon processing industries," is the Managing Partner of Pearson Watson, "an independent energy consultancy with expertise in the natural gas transportation, processing[,] and marketing industries," which was retained by COPC "to perform engineering analysis and render expert opinions regarding the function of" EFS's "pipeline and compression assets" in the San Juan Gathering System. Pearson Report at 4, 5.

[11] At the processing plant, the pressure of the gas from the field typically is raised to 900 psi, thus enhancing the ability to extract NGLPs, which requires a significant drop in pressure, and results not only in NGLPs, but also a residue gas having a pressure of approximately 400 psi, which is then compressed to approximately 880 psi before entering the mainline pipeline at the tailgate of the processing plant. *See* SOR, at 3-4.

We do not doubt that the compression in the field served to increase the amount of production that could be transported to the processing plant. *See* SOR at 3 ("[T]he increased production volumes at issue can reach the plants for processing only because of the global compression–which elevates the pressure of the gas to move greater volumes through the same available pipeline capacities."). However, that was not its only purpose. It also served to incrementally raise the pressure of the gas as it came from the wellhead towards the pressure that was necessary for the gas to be sold, following processing, at the tailgate of the processing plant. Thus, all of the compression costs necessary to render the processed gas marketable, whether they were incurred when the gas was in an unprocessed state or in the course of processing the gas, are not deductible under 30 C.F.R. § 206.153(i) (2006), the marketable condition rule applicable to processed gas.

Moreover, the Pearson Report does not support COPC's position. The report's conclusion that the purpose of the compression was not related at all to "marketing" was based on the fact that the "[p]ressures at key points in the pipeline system upstream of the processing plants before and after the GCP was implemented remained the same." *See* Pearson Report at 7; *see id.* at 23-24. That the pressure at key points in system did not change once the GCP was in place was to be expected; there is no evidence that the pressure of the gas required for transportation from the field to the processing plant materially differed after implementation of the GCP from what it was before implementation of the GCP. More important, however, whether the pressure changed after implementation of the GCP has no bearing on the question of whether the field compression, together with the compression at the plant, were both necessary to bring the pressure of the unprocessed gas at the wellhead up to the pressure required for delivery into the mainline pipeline, at which point the gas was rendered marketable.

COPC asserts that ONRR inappropriately relies on *California Co. v. Udall*, 296 F.2d 384, 388 (D.C. Cir. 1961), which concluded that certain costs associated with placing unprocessed gas in marketable condition were not deductible from royalties because there was "no evidence of a market for the gas in the condition it comes from the wells." SOR at 7. COPC indicates that the gas at issue was marketable in its unprocessed state, prior to compression in the field, and even after compression in the field, prior to transportation to and processing at the plant, before placement into the mainline pipeline. *Id.* ("The gas at issue was sold at the wellhead prior to deregulationn. . . . The condition of the gas has not changed. All that has changed is the place of sale, and it would be plain error to conclude that the gas was not marketable prior to the present point of sale."). But COPC offers no evidence to support this implication. By contrast, we have statements by, or attributed to, the State auditors and ONRR that the gas at issue was only marketable at the tailgate of the processing plant, after it had been compressed in the field and at the plant. *See* Decision at 6 ("The [mainline] pipeline pressure requirements at the tailgate of the

[processing] plants range from 800 to 1,200 [psi]"), 7 ("[T]he pressure at the outlet of the [field] . . . compressors is less than 250 . . . psi."); Order to Pay at 3 ("Global compression boosts the pressure to 250 psi. [ONRR's] position is that the global compression is one of the first steps towards placing production in marketable condition."), 4 ("The mainline [pipeline] is where marketable condition is defined for the San Juan Basin.").

The burden rests on the lessee to demonstrate that the costs were other than the costs necessary to place the gas in a marketable condition, and instead merely necessary to transport the gas. *See, e.g., Burlington Resources Oil & Gas Co.*, 183 IBLA at 352 (citing *Exxon Corp.*, 118 IBLA at 246). Here, we conclude that COPC has failed to carry its burden and thus, the gas must be deemed to have been marketable only at the tailgate of the processing plant, after it had been compressed up to 800 to 1,200 psi. We agree with ONRR that the entire process of treating the gas once it leaves the wellhead, including compression in the field and during processing, ultimately served to render the gas from the wellhead marketable.

ONRR Did Not Apply a "Per Se" Marketable Condition Rule

COPC also objects to ONRR's alleged adoption of a "per se application" of the marketable condition rule, under which compression always serves to place gas in a marketable condition. *See* SOR at 1; *id.* at 9 ("[I]t is simply incorrect, and entirely contrary to precedent to treat compression as if it is invariably utilized only for the purpose of elevating gas to interstate pipeline pressures."); SSOR at 5 ("There is no per se rule that compression is never deductible."). Rather, COPC argues that "the marketable condition rule cannot be divorced from relevant facts," and that ONRR must determine "why the cited expense for transportation is not deductible." SOR at 9.

COPC cites to the Board's decisions in *Xeno, Inc.*, 134 IBLA 172 (1995), and *Exxon Corp.*, 118 IBLA 221 (1991), 98 I.D. 110, in support of its position. *See* SOR at 9-10. In those decisions, the Board held that the costs of dehydration (*Exxon*) and compression (*Xeno*) were properly deducted as transportation costs. We find, however, that the facts in these cases are distinguishable and therefore do not govern the result here.[12]

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[12] COPC also cites to *Phillips Petroleum Co.*, 109 IBLA 4 (1989), in support of its position. But we find no substantive disposition of the question of the deductibility of compression costs in this case, where the Board remanded the case for ONRR to determine "the amount of th[e] [compression] expenses which may be deducted as reasonable transportation costs." 109 IBLA at 13.

In *Xeno*, the Board allowed the lessees to deduct the costs of compressing the gas for royalty valuation purposes because such costs were not necessary to place the gas in a marketable condition. Although the gas was sold by the lessees at the wellhead to a gathering system operator, gathered together with other gas from the field, compressed, and resold to a pipeline company at a higher price, the Board found that there had been shown to exist a market for the uncompressed gas at the wellhead. *See* 134 IBLA at 182-84. The Board noted that there was evidence that "the pressure of the gas from the wellheads was adequate to gain access to the pipeline market," which was reflected in the fact that the lessees had "competing offers to purchase the gas at the wellhead" from two pipeline companies. *Id.* at 183, 184. Thus, the uncompressed gas was already in a marketable condition. *See Amoco Production Co. v. Watson*, 410 F.3d 722, 730 (D.C. Cir. 2005), *aff'd*, 549 U.S. 84 (2006) ("Central to *Xeno* . . . was the fact that the gas was suitable for pipeline access *before* gathering and compression"); *Amerada Hess Corp. v. Department of the Interior*, 170 F.3d 1032, 1037 (10th Cir. 1999) ("*Xeno* reached a different result because the producer company in that case showed that its gas was in marketable condition and could be sold directly from the wellhead"); *Amoco Production Co. v. Baca*, 300 F. Supp. 2d at 11; *Bailey D. Gothard*, 144 IBLA 17, 22 (1998), *aff'd*, *Gothard v. United States*, No. CV 98-103-BLG (D. Mont. June 29, 1999) ("In *Xeno, Inc.*, the Board found that there was evidence that the gas was under sufficient pressure to be marketable at the time it was first sold by the lessees to [the gathering system operator], and that competing offers to purchase the gas at the wellhead were made.").

Similarly, in *Exxon Corp.*, the Board allowed the lessee to deduct the costs of dehydrating the gas because such costs were not necessary to place the gas in a marketable condition. Rather, it had been demonstrated that dehydration, which was performed in the field near the wellhead, was undertaken for the purpose of transporting the gas to a processing plant for the recovery of its constituent components, which were then sold, and not for the purpose of rendering the gas suitable for sale. *See* 118 IBLA at 233-35, 240-42, 98 I.D. at 116-17, 119-20. We specifically noted that, since no market existed for the dehydrated gas, "[dehydration] was not performed to satisfy market specifications." *Id.* at 242, 98 I.D. at 120; *see Amoco Production Co. v. Baca,* 300 F. Supp. 2d at 13 ("[I]n *Exxon Corp.*, 118 I.B.L.A. 221 (1991), the Interior Board of Land Appeals determined that dehydration of the gas at issue was not necessary to satisfy market specifications but rather was performed for the sole purpose of facilitating transportation.").

This Board has held more than once that "the question in each case is whether the typical third party purchaser would accept the gas without the added compression, carbon dioxide removal, and/or dehydration required by the pipeline delivering it." *Encana Oil & Gas (USA), Inc.*, 185 IBLA 133, 141 (2014); *see*

Burlington Resources, 183 IBLA at 354-55, and cases cited. In contrast to *Xeno* and *Exxon*, here we find that COPC has offered no evidence that a competitive market existed for uncompressed gas at the wellhead or following partial compression in the field. Rather, the gas is sold only following transportation from the field and processing in the plant when, as a result of compression in the field and in the plant, the gas is at a substantially higher pressure. There is no evidence that the gas could have been sold at a pressure lower than the 800 to 1,200 psi, at the tailgate of the processing plant. COPC makes no effort, before ONRR or on appeal, to establish that a "'true market,'" in the form of an "'established demand,'" actually existed for the gas in its uncompressed or partially compressed state, and thus other than at the tailgate of the processing plant, following full compression. *Branch Oil & Gas Co.*, 143 IBLA 204, 206 (1998) (quoting *California Co. v. Udall*, 296 F.2d at 388), 207. We thus conclude that the compression costs are royalty-bearing.

ONRR's Determination that the Costs of Compression are Not Properly Deducted as a Transportation Allowance is Supported by the Record

COPC further argues that ONRR failed to provide "any factual basis" for its conclusion, or contradict the facts offered by COPC supporting its position that the purpose of compression was to transport the unprocessed gas to the processing plant. SOR at 1. According to COPC, ONRR failed to carry "the agency's burden to supply a detailed rationale explaining its decision," supported by facts in the administrative record, and thus acted in an arbitrary and capricious fashion. *Id.* at 12.

We find that while ONRR's explanation in its November 2009 Order to Pay and June 2013 Decision for its determination that the costs of field compression are not deductible as a transportation allowance is not detailed, it sufficiently explains ONRR's reasoning—i.e., that while such costs were initially incurred to transport the gas from the field to the processing plant, they ultimately served to place the gas in marketable condition, and thus are not deductible. ONRR reports that the State had determined that the pressure of the gas was less than 250 psi when it left the compressors in the field for transportation to the processing plant and that the gas emerged at the tailgate of the plant at a pressure that ranged from 800 to 1,200 psi. *See* Decision at 6, 7; Order to Pay at 3. ONRR thus concludes that "because none of the compressors at issue meets or exceeds the mainline pipeline pressure requirements, . . . the global compression is for placing the gas into marketable condition." Decision at 7.

Because in this case ONRR's determination was specifically based on the State audit, "the burden rests properly on the lessee to demonstrate that the costs were not necessary to place the unprocessed gas in marketable condition and incurred only to

transport and process its gas." *Burlington Resources Oil & Gas Co.*, 183 IBLA at 352 (citing *Exxon Corp.*, 118 IBLA at 246, 98 I.D. at 122). And here, COPC has not met this burden.

COPC argues that compression is undertaken for the purpose of making the gas suitable for processing and not for making the gas marketable. *See* SOR, MMS-09-0104-O&G, dated Dec. 9, 2009, at 3 (explaining that the processing facility uses a cryogenic process that extracts natural gas liquids from the transported gas, and that the ability to recover natural gas liquids "relies on a significant drop in pressure"). However, even though after being pressurized to less than 250 psi in the field compressors and transported to the processing plant, the pressure of the gas decreased in the course of being processed in the plant, this does not alter the fact that the gas ultimately reached a level of from 800 to 1,200 psi once it exited the plant and was delivered to the mainline pipeline, for transmission to market. In addition, COPC fails to provide any evidence that the pressure of the processed gas at the tailgate of the processing plant was other than what was required by the market for the sale of the processed gas. Nor has it shown that the pressure was not exactly what was specified by the market for the gas. *See id.* at 4 ("[T]he residue gas is compressed to approximately 880 [psi] to enter one of two [mainline] pipelines [at the tailgate of the processing plant], El Paso Natural Gas or Transwestern"). Rather, COPC seems to offer its own per se rule, under which "if the [field] compression is utilized to facilitate transportation of gas that could not otherwise arrive at a plant for processing, the compression is *not* used for the purpose of pressurizing [the] gas to meet a downstream pipeline specification[.]" SSOR at 4 (emphasis in original). Moreover, COPC has offered no evidence that prior to compression at the wellhead or after partial compression in the field the gas is in a condition acceptable to the ultimate purchaser. *Cf. Devon Energy Corp. v. Kempthorne*, 551 F.3d 1030, 1038 (D.C. Cir. 2008), *cert. denied*, 558 U.S. 819 (2009) (Lessee's failure to demonstrate that its gas was actually sold "at pressures less than 1,200 psi under contracts typical for the field or area" could not counter ONRR's application of the marketable condition rule).

On the record in this case, we therefore find that the costs of the original compression in the field and the additional compression at the plant were necessary to render the gas suitable for entry into the mainline pipeline, for the purposes of sale, and thus to place it in a marketable condition. The costs are properly viewed as costs necessary to place the gas in a marketable condition, and thus should be royalty-bearing. *See, e.g., California Co. v. Udall*, 296 F.2d at 388 ("In the record before us there is no evidence of a market for the gas in the condition it comes from the wells."); *The Texas Co.*, 64 I.D. at 79 ("The lessee has not shown that the gas can be marketed at the pressure with which it comes from the wells"). Just as we concluded in *Burlington Resources Oil & Gas Co.*, "[s]ince it is necessary to compress

in order to process the gas and since it is the processed gas (which includes the residue gas and NGL[P]s) that is desirable to typical third-party purchasers, ONRR concluded that it was necessary to compress the unprocessed gas in order to place it in a marketable condition." 183 IBLA at 355; *see also Amoco Production Co. v. Baca*, 300 F. Supp. 2d at 8-9 ("[M]ost of the gas produced by Plaintiffs from the field or area was conditioned to reduce the level of CO_2 because it was sold for use in distant markets. . . . This was true, the Assistant Secretary noted, whether gas was purchased at the wellhead in its natural state and subsequently conditioned by the purchaser, or purchased at the tailgate of a treatment plant after conditioning."), 12 ("The Court finds that, under the particular circumstances in this case, the Assistant Secretary's decision is a reasonable application of the marketable condition rule. Therefore, Plaintiffs must pay royalties on the cost of conditioning the gas to reduce CO_2 levels.").[13]

Although we agree with COPC that the compression of the gas in the field was necessary to transport the gas to the processing plant, this does not change our conclusion that the compression ultimately was necessary to place the gas in a marketable condition, precluding COPC from deducting compression costs for royalty valuation purposes.[14] *See Burlington Resources Oil & Gas Co.*, 183 IBLA at 354-55;

[13] COPC further argues that ONRR's conclusion is "directly contrary" to a Dec. 8, 1995, Memorandum to the Associate Director for Policy and Management Improvement and Associate Director for Royalty Management from the Deputy Director, ONRR (1995 Memorandum) (Ex. 7 attached to Second SSOR, MMS-09-0104-O&G, dated May 31, 2012). SOR at 8. That Memorandum states that the cost of compression "performed to move gas from the lease to the inlet of a processing plant is an allowable deduction from royalty as part of the lessee's cost of transportation." SOR at 8; 1995 Memorandum at 2. However, COPC reads the Memorandum too narrowly, and we do not find ONRR's conclusion in the present case to be contrary to the Memorandum's guidance. While it is correct that the Memorandum provides that compression costs incurred "to move gas" to a processing plant are deductible as a transportation expense, it also provides that compression costs incurred "to boost residue gas to meet the delivery requirement for pressure of the pipeline at the tailgate of the plant" are not deductible, since they are incurred to "plac[e] the gas into marketable condition." 1995 Memorandum at 2. ONRR's conclusion that the compression costs at issue ultimately were incurred to ensure that the residue gas met the mainline pipeline pressure requirements at the tailgate of the plant, and therefore were not deductible, is consistent with the guidance provided by the 1995 Memorandum.

[14] We note that COPC makes no argument and provides no evidence that the compression that occurred *exceeded* what was necessary to place the gas in a

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Devon Energy Corp. v. Kempthorne, 551 F.3d at 1037 (ONRR properly held that the costs of dehydration and compression "are not deductible if their primary function is to prepare the gas to move through the pipelines to the point where the gas is purchased," even if such costs "can reasonably be interpreted to fall within the compass of 'transportation costs.'"); *Amoco Production Co. v. Watson*, 410 F.3d at 731 ("The logic of the regulations bars an expenditure to place gas in marketable condition from also being an expenditure deductible from gross proceeds as a transportation cost"); *Amoco Production Co. v. Baca*, 300 F. Supp. 2d at 13 ("[Unlike dehydration in *Exxon*, which did not place the produced gas in a marketable condition,] CO_2 removal is essential in the instant case to place gas in marketable condition. That there exists a corollary benefit in [transporting and] reducing the level of CO_2 [at the treatment facility] does not transform what is a marketing cost into a transportation cost.").

Conclusion

We conclude that ONRR did not err in its determination that COPC undervalued, for royalty purposes, the gas produced from its Federal leases, during the period from September 2002 through December 2007, by taking deductions from the gross proceeds received on the sale of the gas for the costs of compressing the gas in the field. We therefore affirm the Director's June 2013 Decision, granting in part and denying in part COPC's appeal from ONRR's November 2009 Order to Perform Restructured Accounting and Pay Additional Royalties, and requiring COPC to pay additional royalties, in the total amount of $44,813.45, for sample months, and otherwise to compute and pay any additional royalties found to be due for all non-sample months, during the period from September 1, 2002, through December 31, 2007, with respect to natural gas produced from its Federal onshore oil and gas leases in the San Juan Basin.

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marketable condition, which under the applicable regulations may be deducted as a transportation allowance from the gross proceeds in valuing processed gas for royalty purposes. *See* 30 C.F.R. § 206.157(f)(9) (2006) (transportation allowance may include "[s]upplemental costs for compression, dehydration, and treatment of gas," but "only if such services are required for transportation and exceed the services necessary to place production into marketable condition.").

Accordingly, pursuant to the authority delegated to the Board of Land Appeals by the Secretary of the Interior, 43 C.F.R. § 4.1, the decision appealed from is affirmed.

Amy B. Sosin
Amy B. Sosin
Administrative Judge

I concur:

James F. Roberts
James F. Roberts
Administrative Judge